

Part of the Dynegy
Performance Team

ILLINOIS POWER COMPANY

ANNUAL REPORT ON FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2003

Illinois Power Company

Docket 04-_____

285.305 – General Information Requirements Applicable for all Utilities

Historical Test Year 2003

**Attached 285.305m: Most recent
Securities and Exchange Commission
(SEC) Form 10-K of the utility and any
parent company.**

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549**

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2003

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission file number: 1-3004

ILLINOIS POWER COMPANY

(Exact name of registrant as specified in its charter)

Illinois
(State or other jurisdiction of
incorporation or organization)

500 S. 27th Street
Decatur, Illinois
(Address of principal executive offices)

37-0344645
(I.R.S. Employer
Identification Number)

62521-2200
(Zip Code)

Registrant's telephone number, including area code: **(217) 424-6600**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class:

Name of each exchange on which registered:

Each of the following securities are listed on the New York Stock Exchange.

Mortgage bonds

6 3/4% Series due 2005

7 1/2% Series due 2025

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to the filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes _____
No ☒

Illinova Corporation is the sole holder of the common stock of Illinois Power Company. There is no voting or non-voting common equity held by non-affiliates of Illinois Power Company. Illinova also owns 662,924 shares, or approximately 73%, of IP's preferred stock. Illinois Power Company is an indirect wholly-owned subsidiary of Dynegy Inc.

DOCUMENTS INCORPORATED BY REFERENCE: None.

ILLINOIS POWER COMPANY

FORM 10-K

TABLE OF CONTENTS

	Page
PART I	
Definitions	3
Item 1. Business.....	3
Item 2. Properties	14
Item 3. Legal Proceedings	14
Item 4. Submission of Matters to a Vote of Security Holders	14
PART II	
Item 5. Market for Registrant's Common Equity and Related Stockholder Matters	14
Item 6. Selected Financial Data	15
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	16
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	32
Item 8. Financial Statements and Supplementary Data	33
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.....	33
Item 9A. Controls and Procedures	33
PART III	
Item 10. Directors and Executive Officers of the Registrant	33
Item 11. Executive Compensation	36
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholders Matters	39
Item 13. Certain Relationships and Related Transactions	39
Item 14. Principal Accountant Fees and Services	40
PART IV	
Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K	41
Signatures	42

PART I

Definitions

As used in this Form 10-K, the abbreviations contained herein have the meanings set forth in the glossary beginning on page F-42. Additionally, the terms "IP," "we," "us" and "our" refer to Illinois Power Company and its subsidiaries, unless the context clearly indicates otherwise.

Item 1. Business

General

We are engaged in the transmission, distribution and sale of electric energy and the distribution, transportation and sale of natural gas in the State of Illinois. We provide electric and natural gas service to residential, commercial and industrial customers in substantial portions of northern, central and southern Illinois. Our service territory includes 11 cities with populations greater than 30,000 and 37 cities with populations greater than 10,000 (2000 U.S. Census Bureau's Redistricting Data). We also currently supply electric transmission service to numerous utilities, electric cooperatives, municipalities and power marketing entities in the State of Illinois.

We are an indirect, wholly-owned subsidiary of Dynegy Inc. Dynegy acquired our direct parent company, Illinova, and its subsidiaries, including us, in February 2000. Our operations comprise one of Dynegy's four reportable segments. Dynegy is continuing its self-restructuring efforts and made substantial progress in 2003 in terms of exiting non-core businesses and extending a substantial portion of its debt maturities; however, Dynegy still has substantial debt and other obligations. Our results of operations and financial condition are affected by the consolidated financial and liquidity position of Dynegy, particularly because we rely on interest payments under a \$2.3 billion intercompany note receivable from Illinova for a significant portion of our net cash provided by operating activities. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Our Relationship with Dynegy" for further discussion.

Dynegy and Illinova recently entered into an agreement with Ameren to sell the shares of our common and preferred stock owned by Illinova for \$2.3 billion. The closing of the sale is expected to occur before the end of 2004. However, closing is contingent upon the receipt of required regulatory approvals and other conditions. Please read Note 2 - "Agreed Sale to Ameren" in the accompanying audited financial statements for additional information about this transaction.

We were incorporated under the laws of the State of Illinois on May 25, 1923. Our principal executive office is located at 500 S. 27th Street, Decatur, Illinois 62521-2200, and our telephone number at that office is (217) 424-6600.

Our SEC filings on Forms 10-K, 10-Q and 8-K (and amendments to such filings) are available free of charge through the SEC's website, www.sec.gov. The SEC also has a toll free number that you may call for information, which is 800-732-0330.

Electric Business

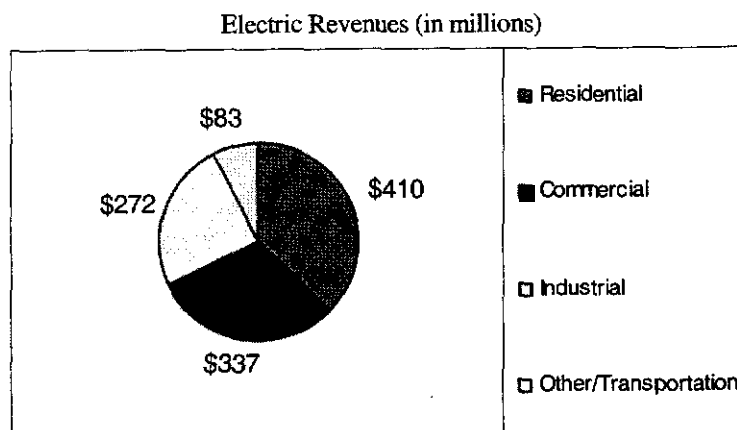
Overview

We supply electric service at retail to an estimated aggregate population of 1,372,000 in 313 incorporated municipalities, adjacent suburban and rural areas and numerous unincorporated communities. We hold franchises in all of the 313 incorporated municipalities in which we provide retail electric service. At year end 2003, based on billable meters, we served 601,082 active electric customers. We own an electric distribution system of 37,765 circuit miles of overhead and underground lines. We also own a 1,672 circuit

mile electric transmission system. For the year ended December 31, 2003, we delivered a total of 18,601 million kWh of electricity.

Our highest system peak hourly demand (native retail load) in 2003 was 3,585,000 kW on August 21, 2003. This compares with our record high system peak hourly demand (native retail load) of 3,888,000 kW on July 29, 1999.

The chart below shows electric revenues by customer class for the year ended December 31, 2003:



Electric Rates

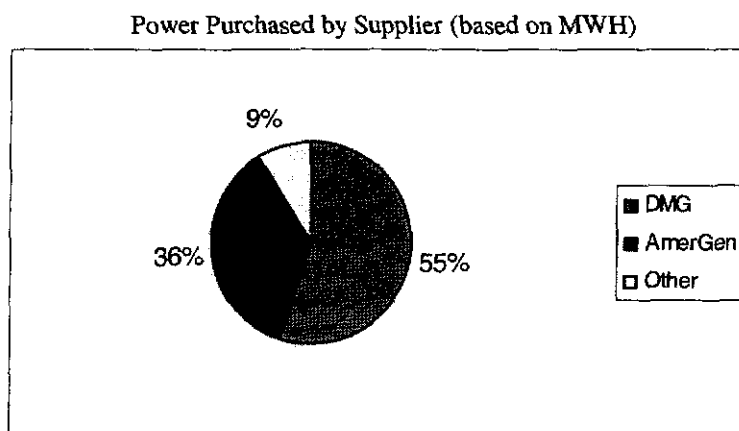
Regulators historically have determined our rates for electric service—the ICC at the retail level and the FERC at the wholesale level. These rates are designed to recover the cost of service and to allow our shareholders the opportunity to earn a reasonable rate of return. Please read “Competition” and “Regulation” below for further discussion of the regulatory environment in which we operate, including the retail electric rate freeze that will remain in effect through 2006.

Power Supply

We own no significant generation assets and obtain the majority of the electricity that we supply to our retail customers through long-term power purchase agreements with AmerGen and DMG. The AmerGen agreement was entered into in connection with the sale of our former Clinton nuclear generation facility to AmerGen in December 1999. We are obligated to purchase a predetermined percentage of Clinton’s electricity output through 2004 at fixed prices that exceed current and projected wholesale prices. At the time of the Clinton sale, we recorded a liability related to the above-market portion of this purchase agreement, which is being amortized through 2004, based on the expected energy to be purchased from AmerGen. The AmerGen agreement does not obligate AmerGen to acquire replacement power for us in the event of a curtailment or shutdown at Clinton.

We have a power purchase agreement with DMG that provides approximately 70% of our capacity requirements. This agreement has a primary term that runs through 2004, with provisions to extend the agreement annually thereafter as the parties shall agree. The DMG agreement requires that we pay DMG for reserved capacity and that we pay for any electricity actually purchased based on a formula that includes various cost factors, primarily related to the cost of fuel, plus a market price for amounts in excess of our reserved capacity. This agreement obligates DMG to provide power up to the amount we reserve even if DMG has individual units unavailable. At our option, DMG is required to provide power in excess of our reserved capacity, but we must pay market prices for any power that DMG purchases in order to satisfy this requirement.

The following chart illustrates the percentage of power purchases by supplier, based on actual total volume of power purchased, for the year ended December 31, 2003:



Our ability to meet our power and energy needs beyond 2004 is addressed in our pending sale to Ameren. Pursuant to a related agreement, which is conditioned upon the closing of the transaction, we will purchase 2,800 MWs of capacity and up to 11.5 million MWh of energy from a Dynegy affiliate at fixed prices for two years beginning in January 2005. Additionally, we will purchase from that Dynegy affiliate 300 MWs of capacity in 2005 and 150 MWs of capacity in 2006 at a fixed price with an option to purchase energy at market-based prices. Any capacity and energy needs not met by this agreement would be secured from either existing agreements, through a specified purchasing process, or, in limited circumstances, through open market purchases. Please read Note 2 - "Agreed Sale to Ameren" in the accompanying audited financial statements for additional information.

The current power purchase agreement between us and DMG requires that notice of termination be presented by December 31, 2003, one year prior to the scheduled expiration period. The parties have agreed to amend the agreement to extend this notice date requirement to March 31, 2004.

In the event that the pending transaction for our sale to Ameren is not completed, the existing agreement with DMG is terminated and no replacement agreement is executed with a Dynegy affiliate, we will be required to purchase a substantial portion of our power on the open market at then current market prices. In the event that the Ameren transaction is not completed and the existing agreement with DMG is either not terminated or is replaced with another agreement with a Dynegy affiliate, we will be required to purchase any amount of capacity and energy not provided under the contract on the open market at then current market prices. Volatility in market prices for power could affect us to the extent that we would be required to purchase power in the open market.

Interconnections

We are a participant, together with AmerenUE and AmerenCIPS, in the Illinois-Missouri Power Pool ("Pool"), which was formed in 1952. The Pool operates under an interconnection agreement that provides for the interconnection of transmission lines. This agreement has no expiration date, but any party may withdraw from the agreement on 36 months written notice.

We, AmerenCIPS and AmerenUE have contracted with the TVA for the interconnection of the TVA system with those of the three companies. The contract addresses power purchase provisions among the parties and other working arrangements. This contract has no expiration date, but any party may withdraw from the agreement on five years written notice.

We also have interconnections with Indiana-Michigan Power Company, Commonwealth Edison Company, AmerenCILCO, MidAmerican Energy Corporation, Louisville Gas & Electric, Southern Illinois Power Cooperative, Electric Energy Inc. and the City of Springfield, Illinois.

We are currently a member of the Mid-America Interconnected Network ("MAIN"), one of ten regional reliability councils established to coordinate plans and operations of member companies regionally and nationally. We had previously given notice to MAIN of our intent to withdraw effective December 31, 2004; however, our membership status will depend upon the outcome of the sale transaction with Ameren. Prior to December 31, 2004, we expect to either extend our membership in MAIN or join one of the other adjacent regional reliability councils.

Illinois Electric Deregulation

Our electric operations are regulated by the State of Illinois through the Illinois Public Utilities Act and the ICC. The ICC regulates the rates at which we can sell and distribute electricity to retail customers. In June 2002, a bill was enacted that extends Illinois' current retail electric rate freeze through 2006. Beginning in 2007, absent further extension of the retail electric rate freeze or other action, we expect that the distribution and transmission component of retail electric rates will continue to be based on cost while the power and energy component may be based on cost or prices in the wholesale market. We cannot predict the structure under which retail rates will be set after 2006 or the impact of any such rate structure on our business.

Please read "Regulation" below for significant legislative actions affecting our electric business.

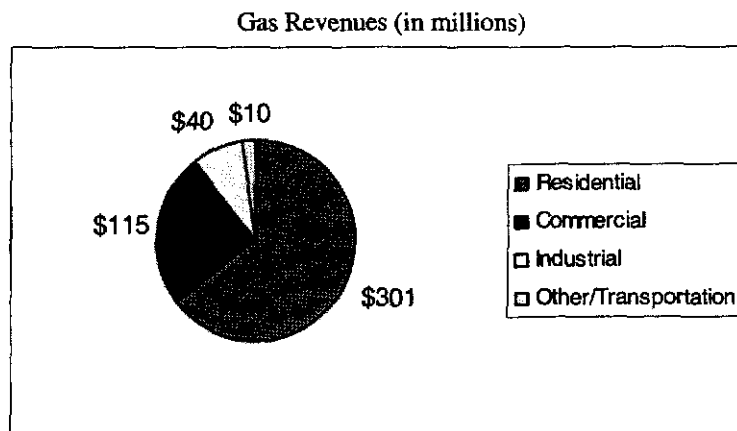
Gas Business

Overview

We supply retail natural gas service to residential, commercial and industrial consumers in substantial portions of northern, central and southern Illinois. We do not sell gas for resale.

We supply retail natural gas service to an estimated population of 1,019,000 in 258 incorporated municipalities and adjacent areas. We hold franchises in all of the incorporated municipalities in which we provide retail gas service. At year end 2003, based on billable meters, we served 415,558 active gas customers. For the year ended December 31, 2003, we delivered a total of 778 million therms of natural gas.

The chart below shows gas revenues by customer class for the year ended December 31, 2003:



We own 763 miles of natural gas transmission pipeline and 7,669 miles of natural gas distribution pipeline. We have contracts on six interstate pipelines for firm transportation and storage services. These contracts have varying expiration dates ranging from 2004 to 2012. We also have contracts for the acquisition of natural gas ranging in duration from one to twelve months. Our customers' gas price volatility during the typical heating season is mitigated to a certain extent through the use of forward pricing instruments and the natural price hedge characteristic of natural gas storage. In addition, natural gas storage enhances the operational reliability of our gas system.

We own seven underground natural gas storage fields with a total capacity of approximately 11.6 billion cubic feet and a total deliverability on a peak day of approximately 339 million cubic feet. To supplement the capacity of our seven underground storage fields, we have contracted with natural gas pipelines for an additional 5.4 billion cubic feet of underground storage capacity, representing additional total deliverability on a peak day of approximately 93 million cubic feet. The operation of these underground storage facilities permits us to increase deliverability to our retail gas customers during peak load periods by withdrawal of natural gas that was previously placed in storage during off-peak months. We experienced our 2003 peak-day send out of 669,379 MMBtu of natural gas on January 23, 2003. This compares with our record peak-day send out of 857,324 MMBtu of natural gas on January 10, 1982.

We continuously monitor the operating efficiencies of our underground gas storage fields. In 1999, we reduced the capacity of our working gas in the Hillsboro gas storage field from 7.6 Bcf to 4.0 Bcf, based on results from an engineering study and the annual operating results of the field, thereby increasing the base gas inventory. During 2003, we initiated further engineering studies; should further adjustments be made based on such studies, any adjustments to inventory would be expected to be recovered from our customers through the purchase gas adjustment clause, subject to ICC prudence review.

Gas Rates

The ICC determines rates that we may charge for retail gas service. As with the rates that we are allowed to charge for retail electric service, these rates are designed to recover our cost of service and to allow our shareholders the opportunity to earn a reasonable rate of return. Our rate schedules contain provisions for passing through to our customers any increases or decreases in the cost of natural gas, subject to an annual prudence review by the ICC. Rates for gas distribution services are set by the ICC in rate proceedings and are based on the underlying costs. Pursuant to the sale agreement with Ameren, we are required to file with the ICC, no later than June 30, 2004, revised gas service tariffs proposing a general increase in base rates for gas service. The approval of the rate case, which will be the first such case we have filed since 1993 in Docket No. 93-0183, will be at the ICC's discretion.

Relationship with Dynegy

As described above, we are an indirect, wholly-owned subsidiary of Dynegy Inc. We rely on Dynegy and other of its affiliates for, among other things, providing funds to Illinova for interest payments under our \$2.3 billion intercompany note receivable from Illinova, a significant portion of our purchased power and certain general and administrative services related to our operations. Because of our relationship with Dynegy, negative events that impact Dynegy can indirectly impact us. To learn more about Dynegy and its current financial condition, we encourage you to read Dynegy's annual report on Form 10-K for the fiscal year ended December 31, 2003, which is available free of charge through the SEC's website at www.sec.gov. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operation - Liquidity and Capital Resources - Our Relationship with Dynegy" for further discussion of the effects that events affecting Dynegy can have and have had on us.

Competition

We are authorized, by statute and/or certificates of public convenience and necessity, to conduct operations in the territories we serve. In addition, we operate under franchises and license agreements granted by the communities we serve.

Our electric utility business faces competition brought about by the implementation of a customer choice structure in the State of Illinois. Under the Customer Choice Law, residential electric customers were given a 15% decrease in their base electric rates beginning August 1, 1998 and an additional 5% decrease in base electric rates beginning May 1, 2002. The Customer Choice Law also implemented a return on equity collar that is further described below under "Regulation." Additionally, the Customer Choice Law phased in the right of customers to choose their electricity suppliers, with specified non-residential customers being granted this right in October 1999, all remaining non-residential customers being granted this right beginning on December 31, 2000 and all residential customers being granted this right effective May 1, 2002. Customers who buy their electricity from a supplier other than the local electric utility are required to pay applicable transition charges to the utility through the year 2006. These charges are not intended to compensate the electric utilities for all revenues lost because of customers buying electricity from other suppliers.

Although no parties have requested certification from the ICC to provide residential electric service pursuant to the Customer Choice Law, this could change. Currently, there are eight energy providers for non-residential service. We face competition from these and other energy providers. By the end of 2003, commercial and industrial customers representing approximately 18% of our commercial and industrial load, more than three-fourths of which relates to one industrial customer, had switched to other energy providers, and we estimate that, by the end of 2004, commercial and industrial customers representing an additional 7% of our commercial and industrial load will have switched to other such providers. Competition typically is based on price and service reliability.

With respect to our gas distribution business, absent extraordinary circumstances, potential competitors are barred from constructing competing systems in our service territories by a judicial doctrine known as the "first in the field" doctrine. In addition, the high cost of installing duplicate distribution facilities would render the construction of a competing system impractical. Additionally, competition in varying degrees exists between natural gas and other fuels or forms of energy available to consumers in our service territories.

Regulation

Federal We are subject to regulation under the Federal Power Act by the FERC as to rates and charges in connection with the transmission of electric energy in interstate commerce, the issuance of debt securities maturing in not more than 12 months, accounting and depreciation policies, interaction with affiliates and certain other matters. The FERC has declared us exempt from the Natural Gas Act and related FERC orders, rules and regulations.

In November 2003, the FERC issued a final rule ("FERC Order 2004") revising the standards of conduct applicable to jurisdictional electric transmission providers (and natural gas pipelines) and their "energy affiliates." The new rule consolidates the previously disparate standards of conduct applicable to electric and natural gas transmission providers, and by broadening the definition of "energy affiliate" expands the range of affiliated entities covered by the standards of conduct. The standards of conduct are designed to ensure that transmission providers do not provide preferential access to service or information to affiliated entities. The new regulations require each transmission provider to file with the FERC and post on its OASIS or internet website a plan and schedule for implementing the standards of conduct and to be in full compliance with the standards of conduct by June 1, 2004. Among other things, the regulations require transmission providers' employees who are engaged in transmission system operations to function independently from the transmission providers' sales or marketing employees and from any employees of their energy affiliates. The regulations also require all transmission providers to designate a regulatory

compliance officer for this purpose who will be responsible for standards of conduct compliance. Transmission providers that are members of RTOs or ISOs may seek an exemption from the rule. Several parties have asked the FERC for clarification and rehearing on many issues outlined in FERC Order 2004. We are currently in compliance with FERC Order 2004 as contemplated.

In April 2003, the FERC issued a white paper on its wholesale power market platform, shifting its focus from market standardization to allow regional state committees to oversee timelines and market designs of RTOs and ISOs in their areas. The ultimate impact of this rulemaking on us is not known at this time

We are an electric utility as defined in the PUHCA. Our direct parent company, Illinova, and Dynegy are holding companies as defined in the PUHCA. However, both Illinova and Dynegy generally are exempt from regulation under section 3(a)(1) of the PUHCA. They remain subject to regulation under the PUHCA with respect to the acquisition of certain voting securities of other domestic public utility companies and utility holding companies.

The U.S. Congress is presently considering passage of comprehensive energy legislation that could impact us. The legislation includes repeal of the PUHCA, enhanced reliability measures, various transmission improvement and financing provisions, and new market reporting requirements. We cannot predict with certainty whether or not the U.S. Congress will finish its work on the energy legislation and send it to the President for signature or what effect any final legislation will have on our business.

State The Illinois Public Utilities Act was significantly modified in 1997 by the Customer Choice Law, but the ICC continues to have broad powers of supervision and regulation with respect to our rates and charges, our services and facilities, extensions or abandonment of service, classification of accounts, valuation and depreciation of property, issuance of securities and various other matters. We must continue to provide bundled retail electric service to all who choose to continue to take service at tariff rates, and we must provide unbundled electric distribution services to all eligible customers as defined by the Customer Choice Law at rates that must be approved by the ICC. During 2003, the ICC ruled on (i) proposed revisions to the current Market Value Index; and (ii) continued suspension of the "neutral fact-finder" procedure. During 2004, we expect the ICC to (i) issue proposed rules on the interconnection of the distributed generation to electric utility systems; (ii) consider the establishment of more uniform line extension and service installation policies for customers of electric and gas utilities; and (iii) begin consideration of how to address the post-2006 period when the current bundled electric rate freeze ends. The impact of these regulations on our financial condition and results of operations cannot be predicted with certainty.

Following is a discussion of the actions taken by the Illinois legislature with respect to the deregulation of the State of Illinois' electric system:

P.A. 92-0537 - Extension of Retail Electric Rate Freeze In June 2002, the Governor of Illinois signed a bill that added two years to the retail electric rate freeze in Illinois. The bill extends through 2006 the mandatory retail electric rate freeze, which was originally required by P.A. 90-561. P.A. 92-0537 freezes our rates for full service, or "bundled," electric service at current levels unless the two-year average of our earned ROE is below the two-year average of the "Treasury Yield," defined as the monthly average yields of the 30-year U.S. Treasury Bonds through January 2002, an average of the 30-year U.S. Treasury Bonds and the monthly Treasury Long-Term Average Rates in February 2002, and the monthly Treasury Long-Term Average Rates (25 years and above) after February 2002, for the concurrent period, in which event we may request a rate increase from the ICC. The ICC would rule on this request for a rate increase using traditional ratemaking standards. As a result of the retail rate freeze, our bundled service retail electric consumers are expected to continue to pay their current electric rates for the next several years. The rate freeze does not apply to our rates for distribution service to customers choosing direct access. These rates are currently required to be based on cost of service and can be raised or lowered subject to approval by the ICC. Beginning in 2007, absent further extension of the retail electric rate freeze or other action, we expect that the distribution and transmission component of retail electric rates will continue to be required to be based on cost while the energy component may be required to be based on cost or prices in the wholesale market.

P.A. 90-561 - Rate Adjustment Provisions P.A. 90-561 gave our residential customers a 15% decrease in base electric rates beginning August 1, 1998. An additional 5% decrease went into effect on May 1, 2002. The approximate rate reduction savings realized by our customers during 2003 and 2002 was \$106.5 million and \$101.6 million, respectively. The combined impact of these rate decreases is expected to result in a total annual revenue reduction of approximately \$104 million in 2004, \$106 million in 2005 and \$108 million in 2006, relative to rate levels in effect prior to August 1, 1998.

The extent to which revenues are affected by P.A. 90-561 will depend on a number of factors, including future market prices for wholesale and retail energy and load growth and demand levels in our current service territory.

P.A. 90-561/92-0537 - Utility Earnings Cap The regulatory reform legislation contains floor and ceiling provisions applicable to our ROE during the mandatory transition period ending in 2006. Pursuant to the provisions in the legislation, we may request an increase in our base rates if the two-year average of our earned ROE is below the Treasury Yield. Conversely, we are required to refund amounts to our customers equal to 50% of the value earned above a defined "ceiling limit." The ceiling limit is exceeded if our two-year average ROE exceeds the Treasury Yield, plus 8.5% in 2002 through 2006. In 2002, we filed to increase the add-on to the Treasury Yield from 6.5% to 8.5%; as a result, we waived our right to collect transition charges in 2007 and 2008. Regulatory asset amortization is included in the calculation of the ROE for the ceiling test but is not included in the calculation of the ROE for the floor test. During 2003, our two-year average ROE was within the allowable ROE collar.

P.A. 90-561 - Direct Access Provisions Since October 1999, non-residential customers with demand greater than 4 MW at a single site, customers with at least 10 sites having aggregate total demand of at least 9.5 MW and customers representing one-third of the remaining load in the non-residential class have been given the right to choose their electric generation suppliers. This right, which we refer to as direct access, was made available for remaining non-residential customers beginning on December 31, 2000. Direct access became available to all residential customers effective May 1, 2002. However, at the present time, there are no Alternative Residential Electric Suppliers registered to provide service to our residential customers. We remain obligated to provide electric service to our customers at tariff rates and to provide delivery service to our customers at regulated rates. Departing customers must pay applicable transition charges to us, but those charges are not designed to compensate us for all of our lost revenues.

Although residential rate reductions and the introduction of direct access have led to lower electric service revenues, P.A. 90-561 is designed to protect the financial integrity of electric utilities in three principal ways:

- Departing customers are obligated to pay applicable transition charges based on the utility's lost revenue from that customer. The transition charges are applicable through 2006.
- Until December 31, 2004, utilities are provided the opportunity to lower their financing and capital costs through the issuance of "securitized" bonds, also called transitional funding trust notes.
- The ROE of utilities is managed through application of floor and ceiling test rules contained in P.A. 90-561/92-0537 as described in the "Utility Earnings Cap" section above.

P.A. 90-561 - ISO Participation Participation in an ISO or RTO by utilities serving retail customers in Illinois was one of the requirements included in P.A. 90-561 and P.A. 92-12.

In January 1998, we, in conjunction with eight other transmission-owning entities, filed with the FERC for all approvals necessary to create and to implement the MISO. On May 8, 2001, the FERC issued an order approving a settlement that allowed us to withdraw from the MISO.

In November 2001, we and seven of the transmission owners proposing to form the Alliance RTO filed definitive agreements with the FERC for approval whereby National Grid would serve as the Alliance RTO's managing member. In an order issued on December 20, 2001, the FERC stated that it could not approve the Alliance RTO, and the FERC directed the Alliance companies to file a statement of their plans to join an RTO, including the timeframe, within 60 days of December 20, 2001.

In May 2002, we submitted a letter to the FERC indicating that we would join PJM either as an individual transmission owner or as part of an independent transmission company. In July 2002, the FERC issued an order approving our proposal to join PJM, subject to certain conditions. These conditions include a requirement that (i) the parties negotiate and implement a rate design that will eliminate rate pancaking between PJM and the MISO; (ii) the North American Electric Reliability Council oversees the reliability plans for the MISO and PJM; and (iii) PJM and MISO develop a joint operation agreement to deal with seams issues. In addition, the FERC initiated an investigation under Federal Power Act Section 206 of the MISO, PJM West and PJM's transmission rates for through and out service and revenue distribution. Subsequent to the July 2002 order, the parties were unable to negotiate a rate design that would eliminate rate pancaking between PJM and the MISO, and the FERC ordered a hearing on this matter.

In orders issued in November 2003, December 2003 and February 2004, the FERC directed the transmission providers, including us, to eliminate the charge for through and out transmission service as applied to requests made on or after November 17, 2003, for service that commences on or after May 1, 2004, when the power being delivered over our transmission system ultimately serves load in the region comprised of PJM, the MISO, AEP, Ameren, Dayton P&L, ComEd or IP. The revenues lost due to the elimination of this charge can be recovered from the loads that benefit by the elimination of such charge via a "lost revenue recovery mechanism." This proceeding is ongoing and includes a period of settlement discussions mandated by the FERC. We submitted the first of two required compliance filings in January 2004 and have a second required compliance filing due in April 2004. The FERC's decision in this proceeding is subject to requests for rehearing and appeal.

The Customer Choice Law requires us to participate in an RTO. Ultimately, any decision we make regarding which RTO to join will be subject to review and approval by the FERC. For several months prior to the execution of the purchase agreement with Ameren, we had suspended our efforts to join an RTO in light of the possible sale. Pursuant to the purchase agreement, we agreed to submit, within 90 days following the purchase date, an application to join the MISO. The timely submission of this application is a condition to the closing of the sale and the application will be conditioned on FERC approval of the sale.

Gas Matters Our retail natural gas sales also are regulated by the ICC. Our sales of gas are currently priced under a purchased gas adjustment mechanism under which our gas purchase costs are passed through to our customers if such costs are determined prudent. Our rates for delivering gas are set by the ICC based on our cost of service. Pursuant to the sale agreement with Ameren, we will file with the ICC no later than June 30, 2004, revised gas service tariffs proposing a general increase in base rates for gas service. The approval of the rate case, which will be the first such case we have filed since 1993 in Docket No. 93-0183, will be at the ICC's discretion.

Please see Note 5 - "Commitments and Contingencies," in the accompanying audited financial statements for a description of the other material regulatory matters affecting us.

Environmental Matters

General We are subject to regulation by various federal and Illinois authorities with respect to environmental matters and may in the future become subject to additional regulation by such authorities or by other federal, state and local governmental bodies. Environmental laws and regulations, including environmental regulators' interpretations of these laws and regulations, are complex, change frequently and have tended to become more stringent over time. Many environmental laws require permits from governmental authorities before construction on a project may be commenced or before wastes or other materials may be discharged into the environment. The process for obtaining necessary permits can be lengthy and complex, and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought either unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures, and we may be required to incur costs to remediate contamination from past releases of wastes into the environment. Failure to comply with these statutes, rules and regulations may result in the assessment of administrative, civil and even criminal penalties. Furthermore, the failure to obtain or renew an environmental permit could prevent operation of one or more of our facilities. We do

not expect that our compliance with any such environmental regulations will have a material adverse effect upon our capital expenditures, earnings or competitive position. For more information, please see Note 5 – “Commitments and Contingencies” in the accompanying audited financial statements.

Baldwin Station Litigation Illinois Power and DMG are the subject of an NOV from the EPA and a complaint filed by the EPA and the Department of Justice in federal district court alleging that we failed to obtain required construction permits in connection with certain repair and maintenance activities at the Baldwin Station in violation of the Clean Air Act and certain related federal and Illinois regulations. The trial to address the claims of liability in this matter concluded in September 2003 and we are awaiting the issuance of a decision from the presiding judge. Please read, Note 5 – “Commitments and Contingencies-U.S. Environmental Protection Agency Complaint” in the accompanying audited financial statements for further discussion of this lawsuit.

Remedial Laws We are also subject to environmental remediation requirements, including provisions of the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, and the corrective action provisions of the federal Resource Conservation and Recovery Act, or RCRA, and similar state laws. CERCLA imposes liability, regardless of fault or the legality of the original conduct, on persons that contributed to the release of a “hazardous substance” into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed, or arranged for the disposal, of the hazardous substance found at a facility. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to public health or the environment and to seek recovery for the costs of cleaning up the hazardous substances that have been released and for damages to natural resources from such responsible party. Further, it is not uncommon for neighboring landowners and other affected parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. CERCLA or RCRA could impose remedial obligations at a variety of our facilities.

In the early 1900s, we operated two dozen sites at which synthetic gas was manufactured from coal. Operation of these MGP sites was generally discontinued in the 1950s when natural gas became available from interstate gas transmission pipelines. Many of these MGP sites were contaminated with residues from the gas manufacturing process and remediation of this historic contamination could be required under CERCLA or RCRA or analogous state laws. We are in the process of cleaning up sites that we have identified as requiring remediation. Recovery of clean-up costs in excess of insurance proceeds is considered probable from our electric and gas customers. For more information on our MGP sites, please see Note 5 - “Commitments and Contingencies” in the accompanying audited financial statements.

Pipeline Safety In addition to environmental regulatory issues, the design, construction, operation and maintenance of some of our pipeline facilities are subject to the safety regulations established by the Secretary of the U.S. Department of Transportation pursuant to the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act, or by state regulations meeting the requirements of the NGPSA and the HLPESA, or to similar statutes, rules and regulations in other jurisdictions. In December 2000, the DOT adopted new regulations requiring operators of interstate pipelines to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could affect so-called “high consequence” environmental impact areas, through periodic internal inspection, pressure testing or other equally effective assessment means. An operator’s program to comply with the new rule must also provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the required assessment and evaluation, and assuring additional protection for the high consequence segments through preventative and mitigative measures. The requirements of this new DOT rule will likely increase the costs of pipeline operations. We believe that such costs will not be material to our financial position or results of operations.

Health and Safety Our operations are subject to the requirements of OSHA and other comparable federal and state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Superfund Amendments and Reauthorization Act and similar state statutes require that information be organized and maintained about hazardous materials used in or produced by our operations. Some of this information must be provided to employees, state and local government authorities and citizens.

We believe we are currently in compliance, and expect to continue to comply in all material respects, with these rules and regulations.

Other Issues Hazardous and non-hazardous wastes that we generate must be managed in accordance with federal regulations under the TSCA, the CERCLA and the RCRA and additional state regulations promulgated under both the RCRA and state law. Regulations promulgated in 1988 under the RCRA govern our use of underground storage tanks. The use, storage and disposal of certain toxic substances, such as polychlorinated biphenyls in electrical equipment, are regulated under the TSCA. Hazardous substances used by us are subject to reporting requirements under the Emergency Planning and Community-Right-To-Know Act. The State of Illinois has been delegated authority for enforcement of these regulations under the Illinois Environmental Protection Act and state statutes. These requirements impose certain monitoring, record keeping, reporting and operational requirements that we have implemented or are implementing to assure compliance. We do not anticipate that compliance with any such environmental regulations will have a material adverse impact on our financial position or results of operations.

Operational Risks and Insurance

We are subject to all risks inherent in the various businesses in which we operate. These risks include, but are not limited to, explosions, fires, terrorist attacks, product spillage, weather, nature and the public, which could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or pollution of the environment, as well as curtailment or suspension of operations at the affected facility. We maintain general public liability and property/boiler and machinery insurance in amounts that we consider to be adequate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. The costs associated with these insurance coverages have increased significantly during recent periods and will more than likely continue to increase in the future. The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our results of operations and financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our potential inability to secure these levels and types of insurance in the future could negatively impact our business operations and financial stability, particularly if a significant uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates we consider commercially reasonable.

Seasonality

Our electric and natural gas sales are affected by seasonal weather patterns. Electricity sales are generally higher during the summer months when warm weather typically requires air conditioner usage. Alternatively, gas sales are generally higher in the winter months when cold weather typically requires gas-fired heater usage. Consequently, our operating revenues and associated operating expenses are not distributed evenly throughout the year.

Significant Customer

No single customer accounted for greater than 10% of our consolidated revenues during 2003, 2002 or 2001.

Employees

At December 31, 2003, we had 564 salaried employees and 1,243 bargaining unit employees. We are subject to collective bargaining agreements with various unions. We consider relations with both bargaining unit and salaried employees to be satisfactory.

Item 2. Properties

We have included descriptions of the location and general character of our principal physical operating properties above in "Item 1, Business." Those descriptions are incorporated herein by this reference. A majority of our assets are pledged as collateral with respect to our mortgage bonds. Please read Note 9 - "Long-Term Debt" in the accompanying audited financial statements for further discussion of our mortgage bonds.

Item 3. Legal Proceedings

For a description of our material legal proceedings, please read "Environmental Matters" and "Other - Legal Proceedings" in Note 5 - "Commitments and Contingencies" in the accompanying audited financial statements.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of security holders during the fourth quarter of 2003.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

All of our common stock is owned by our parent corporation, Illinova. In accordance with the terms of our October 2002 netting agreement with Dynegy, no common stock dividends were paid in 2003. In March 2002 and March 2001, payments of dividends on common stock of \$0.5 million and \$100.0 million, respectively, were made to Illinova, as authorized by the Board of Directors. For more information on our netting agreement, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Affiliate Transactions" below.

In March 2002, we completed a solicitation of consents from our preferred stockholders to amend our Restated Articles of Incorporation to eliminate a provision that limited the amount of unsecured indebtedness that we could issue or assume. Concurrently, Illinova completed a tender offer pursuant to which it acquired 662,924 shares, or approximately 73%, of our preferred stock. The New York Stock Exchange delisted each series of preferred stock that was subject to the tender offer and previously listed thereon. We amended our Restated Articles of Incorporation to eliminate the restriction on incurring unsecured indebtedness. We paid approximately \$1.3 million for charges incurred in connection with the consent solicitation. These charges are reflected as an adjustment to retained earnings in the accompanying Consolidated Balance Sheets.

During 2003 and 2002, we paid the required quarterly dividends on our preferred stock as follows:

<u>Cumulative Preferred Stock Series</u>	<u>Shares Outstanding</u>	<u>Quarterly Dividend Per Share</u>	<u>Quarterly Dividend Paid</u>
4.08%	225,510	\$0.5100	\$ 115,010
4.20%	143,760	\$0.5250	75,474
4.26%	104,280	\$0.5325	55,529
4.42%	102,190	\$0.5525	56,460
4.70%	145,170	\$0.5875	85,287
7.75%	191,765	\$0.96875	185,772
			<u>\$ 573,532</u>

Securities Authorized For Issuance Under Equity Compensation Plans

We are an indirect, wholly-owned subsidiary of Dynegy. None of our employees receive compensation in the form of IP equity. However, there are compensation plans with our employees, including stock option plans, pursuant to which our employees can and do receive stock-based compensation from Dynegy. Please read Dynegy's Annual Report on Form 10-K for the fiscal year ended December 31, 2003 for a discussion of the shares of Dynegy common stock that are reserved for issuance pursuant to these plans. Please read Note 11 - "Common Stock and Retained Earnings" in the accompanying audited financial statements for more information on these stock option plans.

Item 6. Selected Financial Data

The selected financial information presented below was derived from, and is qualified by reference to, our Consolidated Financial Statements, including the Notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial Statements and related Notes and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

SELECTED FINANCIAL DATA

	(Millions of dollars)				
	2003	2002	2001(3)	2000(3)	1999
Operating revenues					
Electric	\$ 1,101.9	\$ 1,138.8	\$ 1,137.1	\$ 1,189.4	\$ 1,178.6
Electric interchange(1)	-	7.1	0.7	2.7	420.2
Gas	465.9	372.4	476.6	393.5	304.4
Total operating revenues	\$ 1,567.8	\$ 1,518.3	\$ 1,614.4	\$ 1,585.6	\$ 1,903.2
Earnings before cumulative effect of change in accounting principle	\$ 119.4	\$ 160.7	\$ 166.2	\$ 134.9	\$ 113.1
Cumulative effect of change in accounting principle, net of tax(2)	\$ (2.4)	-	-	-	-
Net income	\$ 117.0	\$ 160.7	\$ 166.2	\$ 134.9	\$ 113.1
Effective income tax rate	38.9%	39.3%	41.4%	38.2%	38.7%
Net income applicable to common shareholders	\$ 114.7	\$ 158.4	\$ 157.9	\$ 121.0	\$ 95.6
Cash dividends declared on common stock	-	0.5	100.0	-	40.9
Total assets(4)	\$ 5,059.2	\$ 5,050.3	\$ 4,929.3	\$ 5,038.9	\$ 5,363.1
Capitalization					
Common stock equity	\$ 1,484.9	\$ 1,366.2	\$ 1,221.9	\$ 1,156.3	\$ 1,035.2
Preferred stock	45.8	45.8	45.8	45.8	45.8
Mandatorily redeemable preferred stock	-	-	-	100.0	193.4
Long-term debt	1,434.6	1,718.8	1,605.6	1,787.6	1,906.4
Long-term debt to IPSPT(5)	345.6	-	-	-	-
Total capitalization	\$ 3,310.9	\$ 3,130.8	\$ 2,873.3	\$ 3,089.7	\$ 3,180.8
Retained earnings	\$ 504.9	\$ 390.2	\$ 233.6	\$ 175.7	\$ 54.7
Capital expenditures	\$ 125.5	\$ 144.5	\$ 148.8	\$ 157.8	\$ 197.2
Cash flows from operations	\$ 136.3	\$ 209.4	\$ 345.0	\$ 381.3	\$ 85.8
Ratio of earnings to fixed charges	2.18	3.30	3.25	2.53	2.16

- (1) Interchange sales volumes are not comparable year to year due to the October 1999 transfer of our generation assets. Please read Note 4 - "Related Parties" in the accompanying audited financial statements for more information.
- (2) Effective January 1, 2003, we adopted SFAS 143, "Accounting for Asset Retirement Obligations." In accordance with the provisions of SFAS 143, we recorded our ARO obligations as a cumulative effect adjustment, net of tax. Please read Note 1 - "Summary of Significant Accounting Policies - Accounting Principles Adopted" in the accompanying audited financial statements for more information.

- (3) The consolidated financial statements for the years ended December 31, 2001 and 2000 were audited by other independent accountants who have ceased operations. Please read "Report of Independent Public Accountants" in the accompanying audited financial statements.
- (4) SFAS 143, which we adopted in January 2003, requires that cost of removal, which was previously a component of our reserve for depreciation, be reclassified as a regulatory liability. At December 31, 2003, \$72.2 million cost of removal, net of salvage, was reclassified. Total assets for the years 2002, 2001, 2000 and 1999, approximately \$68.7 million, \$68.2 million, \$67.2 million and \$65.3 million, respectively, were adjusted to reflect the effect of SFAS 143. For additional information, please read Note 1 - "Summary of Significant Accounting Policies - Cost of Removal, Net."
- (5) Effective December 31, 2003, IPSPT was deconsolidated from our financial statements in conjunction with the adoption of FIN No. 46R. Please read Note 1 - "Summary of Significant Accounting Policies - Accounting Principles Adopted" in the accompanying audited financial statements for more information.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General - Company Profile

We are engaged in the transmission, distribution and sale of electric energy and the distribution, transportation and sale of natural gas in the State of Illinois. We provide electric and natural gas service to residential, commercial and industrial customers in substantial portions of northern, central and southern Illinois. We are a regulated utility that serves more than 590,000 electricity customers and nearly 415,000 natural gas customers in northern, central and southern Illinois. We generate earnings and cash flows in this business through sales of electric and gas service to residential, commercial and industrial customers. We also currently supply electric transmission service to numerous utilities, electric cooperatives, municipalities and power marketing entities in the State of Illinois.

We are an indirect, wholly-owned subsidiary of Dynegy Inc. Dynegy acquired our direct parent company, Illinova, and its subsidiaries, including us, in February 2000. Our operations comprise one of Dynegy's four reportable segments. Dynegy is continuing its self-restructuring efforts and made substantial progress in 2003 in terms of exiting non-core businesses and extending a substantial portion of its debt maturities; however, Dynegy still has substantial debt and other obligations. Our results of operations and financial condition are affected by the consolidated financial and liquidity position of Dynegy, particularly because we rely on interest payments under a \$2.3 billion intercompany note receivable from Illinova, our direct parent company and a wholly-owned Dynegy subsidiary ("Note Receivable from Affiliate"), for a significant portion of our net cash provided by operating activities. Please read "Liquidity and Capital Resources - Our Relationship with Dynegy" below for further discussion.

We were a leader in the development of the comprehensive electric utility regulatory reform legislation for the State of Illinois, which provided the foundation for our subsequent strategic actions and transformation. Following the successful execution of our strategy to transfer our wholly-owned generating assets to an unregulated affiliate and to exit our nuclear operations, we are now focused on delivering reliable transmission and distribution service in a cost-effective manner.

The earnings and cash flows generated by us are primarily driven by the volumes of electricity and natural gas that we sell. In terms of costs, retail electric rates are frozen through 2006, and gas costs are passed through to customers. The primary factors impacting earnings and cash flows include:

- weather and its effect on demand for our services, particularly with respect to residential electric customers;

- the number of customers that choose another retail electric provider under the Illinois Customer Choice Law;
- our ability to control our capital expenditures, which primarily are limited to maintenance, safety and reliability projects, and new business services and other costs through disciplined management and safe, efficient operations; and
- general economic conditions and the resulting effect on demand for our services, particularly with respect to commercial and industrial customers.

Dynegy and Illinova recently entered into an agreement with Ameren to sell the shares of our common and preferred stock owned by Illinova for \$2.3 billion. The transaction is expected to close before the end of 2004, subject to the receipt of required regulatory approvals and other closing conditions. Please read Note 2 - "Agreed Sale to Ameren" in the accompanying audited financial statements for further discussion.

Liquidity and Capital Resources

Overview

We have a significant amount of leverage, including quarterly payments of approximately \$21.6 million due on the IPSPT transitional funding trust notes through 2008. Because we have no revolving credit facility and no access to the commercial paper markets, we have relied on cash on hand, cash from liquidity initiatives and cash flows from operations, including interest payments under our Note Receivable from Affiliate, to satisfy our debt obligations and to otherwise operate our business. Absent interest payments under our Note Receivable from Affiliate, including the prepayments described below, our cash flows from operations are insufficient to cover our capital expenditures, debt service and other obligations. For the next twelve months, we believe that our cash on hand, cash flows from operations, including interest payments under our Note Receivable from Affiliate, and any necessary additional liquidity support, which Dynegy has committed to provide, will be sufficient to satisfy these obligations. Over the longer term, our liquidity and capital resources are expected to be significantly impacted by the outcome of the pending Ameren transaction. Please read "- Liquidity and Debt Maturities - Conclusion -" below and Note 2 - "Agreed Sale to Ameren" in the accompanying audited financial statements for further discussion.

Our Relationship with Dynegy

As stated above, we are an indirect, wholly-owned subsidiary of Dynegy Inc. We are susceptible to developments at Dynegy because we rely on an unsecured Note Receivable from Affiliate for a substantial portion of our net cash provided by operating activities. The note, which had \$2.3 billion in principal outstanding at December 31, 2003, matures on September 30, 2009 and bears interest at an annual rate of 7.5%, due semiannually in April and October. Because our operating cash flows, cash on hand and other capital resources were insufficient to satisfy our 2003 debt maturities, Dynegy prepaid approximately \$127.8 million of interest on our Note Receivable from Affiliate. In January 2004, we received an additional \$42.6 million of prepaid interest on our Note Receivable from Affiliate. These prepayments were recorded in Deferred Credits - Other on our Consolidated Balance Sheet.

We have reviewed the collectibility of this note to assess whether it has become impaired as required by GAAP. Based upon our assessment, we do not believe that the Note Receivable from Affiliate is impaired. Please read "-Critical Accounting Policies" below for further discussion as to applicable GAAP regarding impairment of the Note Receivable from Affiliate. Principal payments on the Note Receivable from Affiliate are not required until 2009 when it is due in full; as a result, future events may effect our view as to the collectibility of the remaining principal owed us thereunder. It is possible that if negative events affect Dynegy or if we do not receive timely interest payments on the Note Receivable from Affiliate, such matters could cause us to believe it necessary to impair the Note Receivable from Affiliate on our Consolidated Balance Sheet and such action could have a material adverse effect on our financial condition and results of operations.

In connection with Dynegy's agreement to sell our common and preferred stock to Ameren, the Note Receivable from Affiliate is required to be addressed. For more information on the proposed sale and the Note Receivable from Affiliate, please read Note 2 - "Agreed Sale to Ameren" and Note 4 - "Related Parties" in the accompanying audited financial statements.

Liquidity and Debt Maturities

Sources of Liquidity We are currently satisfying our capital requirements primarily with cash flows from operations, cash on hand and interest payments under our \$2.3 billion Note Receivable from Affiliate, including approximately \$170.4 million of prepaid interest received through January 2004.

In December 2002, we sold \$550 million of 11 1/2% Mortgage bonds due 2010 in a private offering. Of the \$550 million, we issued \$400 million in December 2002, with \$150 million issued on a delayed delivery basis subject to ICC approval, which we received in January 2003. The mortgage bonds were sold at a discounted price of \$97.48 to yield an effective rate of 12%. We received net cash proceeds of approximately \$380 million in December 2002 and approximately \$142.5 million in January 2003 from this offering.

Due to our non-investment grade credit ratings and other factors, we do not have access to the commercial paper markets, and our access to the capital markets is limited. These factors, along with the level of our indebtedness and the fact that we do not currently have a revolving credit facility, will have several important effects on our future operations. First, a significant portion of our operating cash flows will be dedicated to the payment of principal and interest on our outstanding indebtedness, including the IPSPT transitional funding trust notes and the increased interest expense associated with our December 2002 \$550 million Mortgage bond financing, and will not be available for other purposes. Second, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes is limited. We therefore expect to continue to rely on Dynegy's commitment to provide additional liquidity as and when needed. Please read Note 2 - "Agreed Sale to Ameren" in the accompanying audited financial statements for a discussion of the pending sale of our company to Ameren, the outcome of which will significantly impact our future liquidity position.

Uses of Liquidity In May 2003, we paid the remaining \$100 million on our one-year term loan using proceeds from our December 2002 \$550 million Mortgage bond offering. In December 2002 we had paid \$200 million on the loan. In August 2003, we repaid \$100 million of mortgage bonds at maturity and in September 2003, we repaid \$90 million of mortgage bonds at maturity. We repaid these bonds using the remaining proceeds from our December 2002 \$550 million Mortgage bond offering and prepaid interest on our Note Receivable from Affiliate.

Debt Maturities As of December 31, 2003, our debt maturities through December 31, 2006 were as follows (millions of dollars):

	2004	2005	2006
IPSPT Transitional Funding Trust Notes			
1 st quarter(1)	\$ 9.5	\$ 21.6	\$ 21.6
2 nd quarter	21.6	21.6	21.6
3 rd quarter	21.6	21.6	21.6
4 th quarter	21.6	21.6	21.6
Tilton Lease (2)			
3rd quarter	81.0		
6 3/4% Mortgage Bonds			
1 st quarter		70.0	
	\$ 155.3	\$ 156.4	\$ 86.4

(1) Due to the adoption of FIN No. 46R and resulting deconsolidation of IPSPT, certain amounts included in restricted cash are netted against the first quarter 2004 maturity, which is included in the current portion of our long-term debt payable to IPSPT on our December 31, 2003 consolidated balance sheet.

(2) Please read "Off-Balance Sheet Financing" below for additional information.

Affiliate Transactions In October 2002, the ICC issued an order approving a netting agreement among us, Dynegy, Illinova and several other Dynegy subsidiaries. Under the netting agreement, we can discharge and satisfy payments due to the other parties to the netting agreement under a Services and Facilities Agreement, or for natural gas and transportation services, by offsetting and netting such payments due against interest due us, but unpaid, under our intercompany note with Illinova, or amounts billed by us to, or owed to us by, the other parties under certain other agreements. Similarly, Illinova would be entitled to discharge and satisfy semiannual interest payments due to us under the intercompany note, and for other services, by offsetting and netting such payments due us against amounts billed to us but unpaid under the Services and Facilities Agreement, which includes tax sharing provisions between us and Dynegy, or for natural gas and transportation services. The netting agreement does not, however, give us a right to offset our payments owed under the power purchase agreement with DMG against the payments due us from Dynegy or its affiliates. Additionally, under the same ICC order, we may not pay any common dividend to Dynegy or its affiliates until our mortgage bonds are rated investment grade by Moody's and Standard & Poor's and specific approval for such payment is obtained from the ICC.

Our financial statements include related-party transactions with IPSPT, our wholly-owned unconsolidated subsidiary, as reflected in the table below (millions of dollars):

	12/31/03(1)	12/31/02
Investment in IPSPT	\$ 4.3	\$ -
Receivable from IPSPT (noncurrent)	\$ 2.2	\$ -
Long-term debt to IPSPT (including due within one year)(2)	\$ 419.9	\$ -

- (1) Effective December 31, 2003, IPSPT was deconsolidated from our financial statements in conjunction with the adoption of FIN No. 46R.
- (2) Due to the adoption of FIN No. 46R and resulting deconsolidation of IPSPT, certain amounts included in restricted cash are netted against the current portion of our long-term debt payable to IPSPT on our December 31, 2003 consolidated balance sheet.

Off-Balance Sheet Financing As previously disclosed, in September 1999, we entered into an \$81 million operating lease on four gas turbines located in Tilton, Illinois. These facilities consist of peaking units with generating capacity of 176 MW. The lease runs until September 2004, with an option to renew for two additional years. In October 1999, we subleased the turbines to DMG. In September 2003, we delivered notice of our intent to purchase the turbines upon expiration of the operating lease in September 2004 but expect the ultimate purchaser to be DMG. As a result of this action, the operating lease was reclassified as a capital lease and we are now the capital sublessor. As a result, we no longer have any off-balance sheet financing arrangements.

Based upon an independent appraisal, we recorded a receivable from DMG at the fair market value of \$66.4 million, which is offset by a corresponding liability to the original lessor. The receivable from DMG and payable to the original lessor will be accreted monthly, using the straight line method to the \$81 million purchase obligation in September 2004. The accretion recorded for 2003 was approximately \$4.3 million and was recorded as interest income offset by the same amount of interest expense. The accretion to be recorded in 2004 will be approximately \$10.3 million. The net effect on our income statement will be zero. This obligation was previously disclosed as a lease obligation in the footnotes to our financial statements and the Commercial Financial Obligations and Contingent Financial Commitments tables in our 2002 Form 10-K.

The following table sets forth our lease expense and lease payments (millions of dollars) relating to Tilton for the periods presented.

	2003	2002
Lease expense	\$2.7	\$2.7
Lease payments (cash flows)	\$2.7	\$2.7

Pursuant to the sublease of these facilities, DMG is concurrently reimbursing us for the lease payments above.

We have determined that we have an Asset Retirement Obligation related to the lease for the Tilton facilities. For further information regarding our ARO, please read Note 1 – “Summary of Significant Accounting Policies” in the accompanying audited financial statements.

Disclosure of Financial Obligations and Contingent Financial Commitments We have entered into various financial obligations and commitments in the course of our ongoing operations and financing strategies. Financial obligations are considered to represent known future cash payments that we are required to make under existing contractual arrangements, such as debt and lease agreements. These obligations may result from general financing activities, as well as from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent contingent obligations that become payable only if certain pre-defined events were to occur, such as funding financial guarantees.

The following table provides a summary of our contractual obligations and commercial commitments as of December 31, 2003 (millions of dollars).

Financial Obligations and Commercial Commitments							
Cash Obligations*	Payments Due by Period						
	Total	2004	2005	2006	2007	2008	Thereafter
Long-Term Debt (1)	\$ 1,444.6	\$ -	\$ 70.0	\$ -	\$ -	\$ -	\$ 1,374.6
IPSPT Transitional Funding							
Trust Notes (2)	419.9	74.3	86.4	86.4	86.4	86.4	-
Capital Lease (3)	83.1	83.1	-	-	-	-	-
Decommissioning							
Charges-Clinton (4)	4.9	4.9	-	-	-	-	-
Decommissioning-DOE (5)	2.2	0.7	0.7	0.8	-	-	-
Unconditional Purchase							
Obligations (6)	429.2	382.5	12.9	9.8	6.1	4.6	13.3
Conditional Purchase							
Obligations (7)	205.0	205.0	-	-	-	-	-
Pension Funding							
Obligation(8)	69.5	2.0	32.5	35.0	-	-	-
Operating Leases (9)(10)	9.7	1.7	1.5	1.4	1.2	1.2	2.7
Total Contractual Cash							
Obligations	\$ 2,668.1	\$ 754.2	\$ 204.0	\$ 133.4	\$ 93.7	\$ 92.2	\$ 1,390.6

*Cash obligations herein are not discounted and do not include related interest or accretion.

- (1) Aggregate principal outstanding under our mortgage bonds approximated \$1.4 billion at December 31, 2003, bearing interest ranging from 1.55% to 11 1/2% per annum. We have a mortgage bond issue of \$70 million maturing in March 2005.
- (2) Reflects the balance of \$864 million of IPSPT Transitional Funding Trust Notes issued by IPSPT in December 1998 as allowed under the Illinois Electric Utility Transition Funding Law in P.A. 90-561. Per annum interest on these notes averages approximately 5.50%. IPSPT is retiring the principal outstanding under these notes utilizing our quarterly payments of \$21.6 million through 2008. Effective December 31, 2003, IPSPT was deconsolidated from our financial statements in conjunction with the adoption of FIN No. 46R. Please read Note 1 – “Summary of Significant Accounting Policies – Accounting Policies Adopted” in the accompanying audited financial statements for additional information.
- (3) Reflects our \$2.1 million annual lease payment and \$81 million purchase obligation related to the capital lease on the Tilton turbines, which will be terminated in 2004. We are subleasing the turbines to our affiliate, DMG, who is responsible for making all such payments on the turbines.
- (4) Reflects decommissioning charges associated with our former Clinton facility. See Note 1 – “Summary of Significant Accounting Policies” in the accompanying audited financial statements included herein for additional information.
- (5) Reflects decontamination and decommissioning charges associated with our use of a DOE facility that enriched uranium for the Clinton Power Station. We were assessed an amount to be paid over fifteen years that would be used to pay for DOE’s decontamination and decommissioning of its facility. Our final payment is due in 2006.

(6) Reflects an unconditional power purchase obligation between us and DMG, another Dynegy affiliate. The agreement requires us to compensate the affiliate for capacity charges through 2004 at a total contract cost of \$310.8 million. We also have contracts on six interstate pipeline companies for firm transportation and storage services for natural gas. These contracts have varying expiration dates ranging from 2004 to 2012, for a total cost of \$66.0 million. We also enter into obligations for the reservation of natural gas supply. These obligations generally range in duration from one to twelve months and require us to compensate the provider for capacity charges. The cost of the agreements is \$38.7 million.

(7) Relates to our expected purchases under the PPA with Amergen. For additional information, please read Item 1 - "Power Supply" above.

(8) This represents the projected benefit funding obligation for our pension plans for salaried and union employees, including \$0.5 million, \$1.9 million, and \$1.9 million in 2004, 2005 and 2006, respectively, relating to our affiliate, DMG. Although we expect to incur significant funding obligations subsequent to 2006, such amounts have not been included in this table because our estimates are imprecise. See Note 12 - "Employee Compensation, Savings and Pension Plans" in the audited financial statements included herein for additional information.

(9) Our primary operating leases reflected above relate to our material distribution facility, Tilton land lease and a lease on 15 line trucks. The material distribution facility is a commercial property lease for our storage warehouse that expires in 2009 and has remaining lease payments of \$3.3 million. The lease on 15 line trucks expires in 2009 and has remaining lease payments of \$1.3 million. The remaining leases included in this line relate to copiers, fax machines, small equipment and building leases.

(10) The Tilton land lease is subleased to DMG, and we satisfy our contractual obligations under this arrangement with payments made by DMG. Lease payments total \$2.4 million for the land lease ending October 2028.

Contingent Financial Obligations Our contingent financial commitments as of December 31, 2003 are listed below. These commitments represent contingent obligations that may require a payment of cash upon certain pre-defined events.

- \$1.8 million in surety bonds expiring during 2004. These bonds are renewed on a rolling twelve-month basis.
- According to the PPA with DMG, we are to provide a security guarantee of \$50 million upon a credit downgrade event. This guarantee is being fulfilled by a \$50 million guarantee from Dynegy on our behalf.
- Dynegy is required to provide collateral to guarantee payment of deductibles for insurance claims and has assigned \$12 million to us as our share of its total corporate requirement.

Credit Ratings As of February 27, 2004, our credit ratings, as assessed by the three major credit rating agencies, were as follows:

Standard &		
Moody's	Poor's	Fitch
Senior secured debt	B	B
Senior unsecured debt	*	CCC+
Preferred stock	CCC	CC
*Not rated		

(1) Reflects a February 2004 two-notch ratings upgrade by Moody's Investors Service, who cited the pending sale to Ameren and indicated that our credit ratings remained under review for further upgrade. B1 is four notches below investment grade.

Our non-investment grade status has limited our ability to refinance our debt obligations as they mature and limits our access to the capital markets. Our non-investment grade status also will likely increase the borrowing costs incurred in connection with any such actions. Our financial flexibility has likewise been reduced as a result of, among other things, restrictive covenants and other terms typically imposed on non-investment grade borrowers. For a description of the restrictions included in our 1 1/2% Mortgage bonds issued in December 2002 and January 2003, please read Note 9 - "Long-Term Debt" in the accompanying audited financial statements.

We have been requested to provide letters of credit or other credit security to support certain business transactions, including our purchase of natural gas and natural gas transportation. As of December 31, 2003, Dynegy posted \$26 million in letters of credit in support of these transactions. Additionally, in July

2002, some of our suppliers began to require us to accelerate payment for some of our natural gas purchases.

Dividends There are restrictions on our ability to pay cash dividends, including any dividends that we might pay indirectly to Dynegy. Under our Restated Articles of Incorporation, we may pay dividends on our common stock, all of which is owned by Illinova, subject to the preferential rights of the holders of our preferred stock, of which Illinova owns approximately 73%. We also are limited in our ability to pay dividends by the Illinois Public Utilities Act and the Federal Power Act, which require retained earnings equal to or greater than the amount of any proposed dividend. In 2003, we did not pay any dividends on our common stock; however, we paid \$0.5 million of dividends on our common stock to Illinova in March of 2002. Additionally, the ICC's October 23, 2002 order relating to a netting agreement between us and Dynegy prohibits us from declaring and paying any dividends on our common stock until such time as our mortgage bonds are rated investment grade by both Moody's and Standard & Poor's and further requires that we first obtain approval for any such payment from the ICC.

Capital Expenditures Capital expenditures for 2003 were approximately \$125.5 million. Capital expenditures consist of numerous projects to upgrade and maintain the reliability of our electric and gas transmission and distribution systems, add new customers to the system and prepare for a competitive environment. Our capital expenditures for 2004 are expected to total approximately \$140 million. Additional expenditures may be required during this period to accommodate the transition to a competitive environment, environmental compliance, system upgrades and other costs that cannot be determined at this time.

Commitments and Contingencies Please read Note 5 - "Commitments and Contingencies," which is incorporated herein by reference, for a discussion of our commitments and contingencies.

Conclusion We have a significant amount of indebtedness, including quarterly payments of approximately \$21.6 million due on the IPSPT transitional funding trust notes through 2008.

Due to our non-investment grade credit ratings and other factors, we do not have access to the commercial paper markets, and our access to the capital markets is limited. These factors, along with the level of our indebtedness and the fact that we do not currently have a revolving credit facility, will have several important effects on our future operations. First, a significant portion of our cash flows will be dedicated to the payment of principal and interest on our outstanding indebtedness, including the increased interest expense associated with our December 2002 \$550 million Mortgage bond financing, and will not be available for other purposes. Second, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes is limited.

For the near term, our debt maturities primarily comprise (i) quarterly payments on the IPSPT transitional funding trust notes, for which we receive a separate revenue stream from our customers; and (ii) an \$81 million payment on our Tilton lease in September 2004, which we expect to receive from DMG under the sublease agreement. We believe that we have sufficient internal liquidity sources, including Dynegy's commitment of support, to satisfy these debt maturities and our commercial obligations for the next twelve months. Importantly, while Dynegy's restructured credit facility, which expires in February 2005, prohibits it from prepaying more than \$200 million in principal under our Note Receivable from Affiliate during the term of the credit agreement, it does not limit Dynegy's ability to prepay interest under our Note Receivable from Affiliate. In addition, the indenture governing Dynegy Holdings Inc.'s second priority senior secured notes permits payments of principal on the intercompany note receivable up to \$450 million or to the extent that a fixed charge coverage ratio of 2:1 is satisfied. The indenture also permits the prepayment of interest on the intercompany note receivable up to twelve months at any one time.

Over the longer term, our liquidity and capital resources will be materially affected by the outcome of the pending sale of our company to Ameren. If the sale is consummated, Ameren has committed to contribute cash to us in order to support our ongoing operating commitments and to reduce our leverage. If the sale is not consummated, we would explore other liquidity initiatives. These initiatives would include an integration of many processes into those of Dynegy's, which we expect would yield significant cost savings. Another liquidity initiative could include an issuance of mortgage bonds or transitional funding trust notes. Based on our December 31, 2003 financial statements, we could issue approximately \$709 million in

mortgage bonds under our 1992 Mortgage. Until December 31, 2004, we also have the ability to cause the issuance by IPSPT, subject to ICC approval, of up to \$864 million in additional transitional funding trust notes pursuant to the Illinois Electric Utility Transitional Funding Law. However, under the supplemental indenture we executed in connection with the issuance of our 11 1/2% Mortgage bonds due 2010, we could be required to redeem these bonds if we were to cause the issuance of more than \$300 million of transitional funding trust notes.

Our ability to consummate other liquidity initiatives, as described above, is subject to a number of risks, some of which are beyond our control. The outcome of the agreed sale to Ameren is also subject to a number of risks, some of which are beyond our control. These risks include, among others, the receipt of required regulatory approvals, particularly from the ICC, and satisfaction of other closing conditions. We encourage you to read Dynegy's Annual Report on Form 10-K for the year ended December 31, 2003 for additional information regarding Dynegy and its current liquidity position.

Reference is also made to the section "Uncertainty of Forward-Looking Statements and Information" below for additional factors that could impact our future operating results.

Critical Accounting Policies

Our Accounting Department is responsible for the development and application of accounting policy and control procedures for the organization's financial and operational accounting functions. This department conducts its activities independent of our business units and reports to Dynegy's Corporate Controller.

We have identified the following critical accounting policies, which require a significant amount of judgment and are considered to be the most important to the portrayal of our financial position and results of operations:

- revenue recognition;
- long-lived assets;
- note receivable from affiliate;
- regulatory asset amortization;
- valuation of pension assets and liabilities; and
- accounting for income taxes.

Revenue Recognition Revenues for utility services are recognized when services are provided to customers. As such, we record revenues for services provided but not yet billed. Unbilled revenues represent the estimated amount customers will be billed for service delivered from the time meters were last read to the end of the accounting period. The estimate is based upon a percentage ratio of daily deliveries into our system throughout the month. A percentage is assigned to each daily delivery representing the portion that will not be billed by the end of the month. The unbilled deliveries are allocated to a revenue class based on current month billed ratios and priced at an average price by class.

Long-lived Assets The estimated useful lives of our long-lived assets are used to compute depreciation expense and are also used for impairment testing. Estimated useful lives are based on the assumption that we provide an appropriate level of capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly. These estimates could be impacted by regulatory actions and competition. If the useful lives of these assets are determined to differ from the original estimate, depreciation rates would be adjusted prospectively.

Note Receivable from Affiliate As described above, we hold a \$2.3 billion Note Receivable from Affiliate. We are required to review the collectibility of this note to assess whether it has become impaired under the criteria of SFAS No. 114, "Accounting by Creditors for Impairment of a Loan." Under this standard, a loan is impaired when, based on current information and events, it is "probable" that a creditor will be unable to collect all amounts due according to the contractual terms of the loan agreement. However, if the possibility that we would not be able to collect all amounts due under the contractual terms were only "more likely than not" or "reasonably possible" but not probable, then the Note Receivable from Affiliate would not be

considered impaired under SFAS 114. The use of the terms "probable," "reasonably possible" and "more likely than not" are used in FAS No. 5, "Accounting for Contingencies," as follows:

- Reasonably possible – The chance of the future event or events occurring is more than remote but less than likely.
- More likely than not – A level of likelihood that is more than 50%.
- Probable – Future events are likely to occur.

A collectibility assessment in accordance with SFAS 114 is highly subjective given the inherent uncertainty of predicting future events, and principal payments on our Note Receivable from Affiliate are not required until 2009 when it is due in full. We evaluate the range of likelihood of collectibility of our Note Receivable from Affiliate on a quarterly basis utilizing, among other things, our review of the status of Dynegy's financial condition, the market's view of Dynegy's debt and stock price, and Dynegy's earnings and cash flow guidance. Any change in assumption or estimate could result in a different outcome. In the future should we conclude that an impairment has occurred, we would measure the note's realizable value, which may exceed its fair value, based on a probability weighted analysis of multiple expected future cash flows discounted at the note's effective interest rate of 7.5%, as opposed to a market rate of interest, in accordance with SFAS 114.

Regulatory Asset Amortization P.A. 90-561 allows utilities to recover potentially non-competitive investment costs ("stranded costs") from retail customers during the transition period, which extends until December 31, 2006. During this period, we are allowed to recover stranded costs through frozen bundled rates and transition charges from customers who select other electric suppliers. The amount of amortization recorded in each period is based on the recovery of such costs from the rate payers as measured by our ROE, based on actual and projected recovery of such costs. If different judgments were applied to the projected recovery of these costs, the outcome could differ materially from our estimates. Please read Note 1 - "Summary of Significant Accounting Policies" for additional information on our regulatory asset amortization.

Valuation of Pension Assets and Liabilities Our employees participate in defined benefit pension plans sponsored by Dynegy. The values and discussion below represent the components of the Dynegy defined benefit plans that were sponsored by us prior to the merger with Dynegy. Plan participants include Illinova employees as of February 1, 2000, as well as our employees and employees of DMG hired subsequent to the merger. We are reimbursed by the other Illinova subsidiaries (prior to the merger) and by other Dynegy subsidiaries (subsequent to the merger) for their share of the expenses of the benefit plans. Please see Note 12 - "Employee Compensation, Savings and Pension Plans" in the audited financial statements included herein for more information.

Our pension and postretirement benefit costs are developed from actuarial valuations. Inherent in these valuations are key assumptions provided by us to our actuaries, including the discount rate and expected long-term rate of return on plan assets. Material changes in our pension and postretirement benefit costs may occur in the future due to changes in these assumptions, changes in the number of plan participants, and changes in the level of benefits provided.

The discount rate is subject to change each year, consistent with changes in applicable high-quality, long-term corporate bond indices. Long-term interest rates declined during 2003. Accordingly, at December 31, 2003, we used a discount rate of 6.0%, a decline of 50 basis points from the 6.5% rate used as of December 31, 2002. This decline in the discount rate had the impact of increasing the underfunded status of our pension plans by approximately \$41 million.

The expected long-term rate of return on pension plan assets is selected by taking into account the expected duration of the projected benefit obligation for the plans, the asset mix of the plans, and the fact that the plan assets are actively managed to mitigate downside risk. Based on these factors, our expected long-term rate of return as of January 1, 2004 is 8.75%, compared with 9.00% during 2003. This change did not impact 2003 pension expense, but it will adversely impact pension expense beginning in 2004. We expect the decrease in this assumption, coupled with the decreased discount rate discussed above and the passage of time, will increase 2004 pension expense by approximately \$10.5 million.

On December 31, 2003, our annual measurement date, the excess of accumulated benefit obligation related to our pension plans continued to exceed the fair value of the pension plan assets (such excess is referred to as an unfunded accumulated benefit obligation). This difference is attributed to (1) an increase in the accumulated benefit obligation that resulted from the decrease in the discount rate and the expected long-term rate of return and (2) a decline in the fair value of the plan assets due to a sharp decrease in the equity markets through December 31, 2002, which was partially recovered during 2003. As a result of the 2003 partial recovery, in accordance with SFAS No. 87, "Employers' Accounting for Pensions", we recognized a credit to other comprehensive income of \$6.3 million (net of taxes of \$3.8 million), which increased common stock equity. The cumulative charge to common stock equity for the excess of additional pension liability over the unrecognized prior service cost represents a net loss not yet recognized as pension expense.

The following table illustrates the effect that changes in the assumptions made for discount rate and rate of return would have had on our pension plan assets and liabilities (millions of dollars):

	PBO** 12/31/2004	2004 Expense
2004 estimate*	\$ 853.2	\$ 25.9
Impact of changes in rate assumptions:		
Increase Discount Rate 50 basis points	\$ (54.2)	\$ (5.0)
Decrease Discount Rate 50 basis points	\$ 59.8	\$ 5.4
Increase Expected Rate of Return 50 basis points	\$ -	\$ (3.0)
Decrease Expected Rate of Return 50 basis points	\$ -	\$ 3.0

*Liabilities projected from December 31, 2003 to December 31, 2004 assuming no gains or losses. Assets projected from December 31, 2003 to December 31, 2004 assuming an 8.75% return.

** Pension Benefit Obligation

We expect to make \$2 million in cash contributions related to our defined benefit pension plans during 2004. In addition, it is likely that we will be required to continue to make contributions to the pension plans beyond 2004. Although it is difficult to estimate these potential future cash requirements due to uncertain market conditions, we currently expect that the cash requirements would be approximately \$33 million in 2005 and \$35 million in 2006.

Accounting for Income Taxes We follow the guidelines in SFAS No. 109, "Accounting for Income Taxes," which require that we use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant income tax temporary differences. Please read Note 8 – "Income Taxes" in the accompanying audited financial statements for additional information.

As part of the process of preparing our financial statements, we are required to estimate our income taxes. This process involves estimating our actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within our Consolidated Balance Sheets.

Results of Operations

Overview In this section we discuss our results of operations on a consolidated basis for 2003, 2002 and 2001. Our operations consist of a single reportable segment. This segment includes the transmission, distribution and sale of electric energy; and the transportation, distribution and sale of natural gas in Illinois. Also included in this segment are specialized support functions, including accounting, legal, regulatory, information technology, human resources, environmental resources, purchasing and materials management and communications. At the end of this section, we have included our 2004 outlook.

Net Income We had net income of \$117.0 million in 2003. This compares with net income of \$160.7 million and \$166.2 million in 2002 and 2001, respectively. The decrease in 2003 earnings compared to 2002 was due to lower electric sales due to cooler than normal summer weather and the full year impact of the 5% residential rate reduction effective May 1, 2002. In addition, results were negatively impacted by higher operating expenses and interest expense, partially offset by lower amortization of regulatory assets. The decrease in 2002 earnings compared to 2001 was due to the 5% residential rate reduction effective May 1, 2002, offset by favorable weather-driven sales from residential and commercial customers. In addition, results were favorably impacted by increased operating efficiencies and litigation and billing settlements, offset by increased regulatory asset amortization.

The following table provides summary financial data regarding our results of operations for 2003, 2002 and 2001, respectively.

	Year Ended December 31,		
	2003	2002	2001
	<i>(Millions of dollars)</i>		
Electric Operations:			
Revenues	\$ 1,101.9	\$ 1,145.9	\$ 1,137.8
Electricity Purchased	(681.0)	(677.5)	(661.8)
Gas Operations:			
Revenues	465.9	372.4	476.6
Gas Purchased	(315.5)	(231.7)	(332.8)
Other Expenses	(325.2)	(348.2)	(344.3)
General Taxes	(67.5)	(57.6)	(68.4)
Income Taxes	(12.4)	(39.3)	(40.6)
Other Income and Deductions – Net	116.1	109.1	121.5
Interest Charges	(162.9)	(112.4)	(121.8)
Cumulative effect of change in accounting principle	(2.4)	-	-
Net Income	\$ 117.0	\$ 160.7	\$ 166.2
Net Non-Cash Items Included in Net Income	109.5	117.5	112.4
Operating Cash Flows Before Changes in Working Capital	226.5	278.2	278.6
Increase (Decrease) in Working Capital	(90.2)	(68.8)	66.4
Net Cash Provided by Operating Activities	\$ 136.3	\$ 209.4	\$ 345.0
Net Cash Used in Investing Activities	\$ (125.5)	\$ (141.1)	\$ (146.7)
Net Cash Provided by (Used in) Financing Activities	\$ (111.5)	\$ 7.8	\$ (168.6)

The following table provides operating statistics regarding our results of operations for 2003, 2002 and 2001, respectively.

	Year Ended December 31,		
	2003	2002	2001
Electric Operations:			
Electric Sales Revenues (in millions):			
Residential	\$ 410.3	\$ 435.8	\$ 431.4
Commercial	337.2	338.0	332.0
Commercial-distribution	0.1	0.1	1.5
Industrial	272.0	281.8	288.0
Industrial-distribution	5.6	5.6	3.6
Other	38.8	38.3	39.3
Interchange	-	7.1	.7
Transmission/Wheeling	37.9	39.2	41.3
Total Electric Sales Revenues	<u>\$ 1,101.9</u>	<u>\$ 1,145.9</u>	<u>\$ 1,137.8</u>
Electricity Purchased	<u>\$ 681.0</u>	<u>\$ 677.5</u>	<u>\$ 661.8</u>
Electric Sales in kWh (in millions):			
Residential	5,309	5,548	5,202
Commercial	4,413	4,415	4,337
Commercial-distribution	4	2	40
Industrial	6,123	6,306	6,353
Industrial-distribution	2,378	2,503	2,605
Other	372	368	371
Sales to ultimate consumers	<u>18,599</u>	<u>19,142</u>	<u>18,908</u>
Interchange	<u>2</u>	<u>2</u>	<u>2</u>
Total Electricity Delivered	<u>18,601</u>	<u>19,144</u>	<u>18,910</u>
Cooling Degree Days	980	1,467	1,302
Cooling Degree Days – 10 Year Rolling Average	1,214	1,246	1,297
Gas Operations:			
Gas Sales Revenues (in millions):			
Residential	\$ 301.2	\$ 243.4	\$ 298.0
Commercial	114.7	89.0	112.4
Industrial	39.6	27.3	45.3
Other	10.4	12.7	20.9
Total Gas Sales Revenues	<u>\$ 465.9</u>	<u>\$ 372.4</u>	<u>\$ 476.6</u>
Gas Purchased	<u>\$ 315.5</u>	<u>\$ 231.7</u>	<u>\$ 332.8</u>
Gas Sales in Therms (in millions):			
Residential	337	323	315
Commercial	145	137	136
Industrial	57	58	70
Sales to ultimate consumers	<u>539</u>	<u>518</u>	<u>521</u>
Transportation of Customer-Owned Gas	<u>226</u>	<u>233</u>	<u>246</u>
Total gas sold and transported	<u>765</u>	<u>751</u>	<u>767</u>
Sales to affiliates	<u>13</u>	<u>22</u>	<u>18</u>
Total Gas Delivered	<u>778</u>	<u>773</u>	<u>785</u>
Heating Degree Days	5,256	5,118	4,749
Heating Degree Days – 10 Year Rolling Average	4,930	5,002	5,032

Electric Operations

Electric Revenues For the years 2001 through 2003, electric revenues, including interchange, decreased 3%. Electric revenues, excluding interchange, were \$1,101.9 million in 2003 compared to \$1,138.8 million and \$1,137.1 million in 2002 and 2001, respectively. The decrease in electric revenues in 2003 compared to 2002 reflect lower sales volume due to cooler than normal summer weather for residential sales, the full year impact of the 5% residential rate decrease that was effective May 1, 2002 and lower industrial sales due to the combined effect of customers choosing alternative suppliers and general economic conditions. The increase in electric revenues in 2002 compared to 2001 reflected an increase in sales volume due to favorable weather partially offset by a 5% residential rate reduction effective May 1, 2002. Interchange revenues were \$0 million, \$7.1 million and \$.7 million for 2003, 2002 and 2001, respectively. Interchange revenues in 2002 reflect the reversal of a contingent liability for a bulk power billing dispute that was settled for less than the reserve.

The components of annual changes in electric revenues excluding interchange were:

<i>(Millions of dollars)</i>	2003	2002
Price	\$ (7.2)	\$ (22.2)
Volume and other	(29.7)	23.9
Electric revenue increase (decrease)	<u>\$ (36.9)</u>	<u>\$ 1.7</u>

Electricity Purchased Electricity purchased increased \$3.5 million in 2003 due to a higher average cost per unit offset by lower purchased volumes due to reduced demand resulting from cooler than normal summer weather and general economic conditions. The increase in electricity purchased in 2002 of \$15.7 million was primarily due to higher sales associated with warmer than normal summer weather, partially offset by a lower average per unit cost.

Changes in the cost of electricity purchased to serve our native load were:

<i>(Millions of dollars)</i>	2003	2002
Electricity purchased:		
Price	\$ 30.4	\$ (6.2)
Volume	(26.9)	21.9
Electricity cost increase	<u>\$ 3.5</u>	<u>\$ 15.7</u>

Gas Operations

Gas Revenues For the years 2001 through 2003, gas revenues, including transportation, decreased 2%. Gas revenues excluding transportation revenues were \$468.0 million in 2003 compared to \$372.1 million and \$469.8 million in 2002 and 2001, respectively. Transportation revenues were (\$2.1) million, \$.4 million and \$6.8 million in 2003, 2002 and 2001, respectively. The 2003 increase in gas revenues was a direct result of higher natural gas prices which are passed through to our end use customers and colder than normal weather in the first quarter, which resulted in higher demand from residential and commercial customers. The 2002 decrease in gas revenues was a direct result of lower natural gas prices offset by weather-driven residential sales.

The components of annual changes in gas revenues excluding transportation revenues were:

<i>(Millions of dollars)</i>	2003	2002
Price	\$ 77.0	\$ (97.0)
Volume and other	18.9	(0.7)
Gas revenue increase (decrease)	<u>\$ 95.9</u>	<u>\$ (97.7)</u>

Gas Purchased The 2003 increase in gas purchases related to higher prices for natural gas and weather driven residential and commercial sales. The 2002 decrease in gas purchases are related to lower prices for natural gas offset by weather-driven residential sales.

Changes in the cost of gas purchased to serve our native load were:

<i>(Millions of dollars)</i>	2003	2002
Gas purchased:		
Price	\$ 87.8	\$ (68.1)
Volume	(3.7)	7.6
Gas cost recoveries	(0.3)	(40.6)
Gas cost increase (decrease)	\$ 83.8	\$ (101.1)

Other Expenses Other expenses were \$325.2 million in 2003 compared to \$348.2 million and \$344.3 million in 2002 and 2001, respectively. A comparison of significant increases (decreases) in other operating expenses, maintenance, retirement and severance, and depreciation and amortization for the last two years is presented in the following table:

<i>(Millions of dollars)</i>	2003	2002
Other operating expenses	\$ 6.2	\$ (2.1)
Maintenance	4.2	(0.7)
Retirement and severance expense	0.7	(16.0)
Depreciation and amortization	(2.2)	(0.2)
Amortization of regulatory assets	(31.9)	22.9
Other expenses increase (decrease)	\$ (23.0)	\$ 3.9

The increase in other operating and maintenance expense for 2003 over 2002 was primarily due to higher employee benefit costs, insurance claims and an increase in legal reserves as a result of additional legal activity, partially offset by operating efficiencies. The decrease in retirement and severance expense in 2002 was due to an early retirement/severance program we offered in 2001 related to a corporate reorganization.

In 2003, there was a slight decrease in depreciation and amortization as a result of lower capital expenditures. In 2002, our increased financial performance allowed us to recognize additional regulatory asset amortization and stay within the allowable ROE collar. Therefore, the annual amortization of our regulatory assets was reduced in 2003.

General Taxes General taxes increased \$9.9 million in 2003 primarily because 2002 general tax expense benefited from a favorable audit conclusion for utility taxes and an adjustment in our municipal utility taxes ("MUT"). The decrease in general taxes of \$10.8 million in 2002 was attributable to the 2002 audit conclusion and adjustment to MUT discussed above as well as lower gas revenue taxes resulting from lower gas prices in 2002, partially offset by a favorable 2001 Invested Capital Tax dispute settlement with the Illinois Department of Revenue.

Income Taxes See Note 8 - "Income Taxes" in the accompanying audited financial statements for additional information on current and deferred income taxes and analysis of federal and state income tax.

Other Income and Deductions - Net The increase of \$7.0 million in 2003 of other income and deductions - net was attributable to the remeasurement of our ARO, along with reduced losses on disposal of property and general reduction in non-operating expenses. See Note 1 - "Summary of Significant Accounting Policies" in the accompanying audited financial statements for additional information. For 2002, the decrease in other income and deductions - net was attributable to favorable insurance and litigation settlements in 2001 partially offset by a favorable litigation settlement in 2002.

Interest Charges Total interest charges, including AFUDC, increased \$50.5 million in 2003 substantially due to our \$550 million 11 1/2% Mortgage bonds outstanding, partially offset by the reduction in the IPSPT

transitional funding trust notes and the redemption of our \$100 million and \$90 million Mortgage bonds in August and September, respectively. In addition, the 2003 increase in interest charges is partially offset by the repayment of our \$300 million term loan, \$200 million of which was repaid in December 2002 with the remaining \$100 million paid in May 2003. Total interest charges, including AFUDC, decreased \$9.4 million in 2002, primarily due to the ongoing redemption of the IPSPT transitional funding trust notes, and lower average long-term debt balances coupled with lower interest charges on short-term debt. See "Note 7 - Revolving Credit Facilities and Short-Term Loans" and Note 9 - "Long-Term Debt" in the accompanying audited financial statements for additional information.

Operating Cash Flow Operating cash flows were \$136.3 million for the year ended December 31, 2003 compared to \$209.4 million and \$345.0 million for the year ended December 31, 2002 and 2001, respectively. The changes in net income period to period, including the components related to depreciation and amortization, have been previously discussed. The changes in working capital relate primarily to timing differences in cash flows. Cash flow was positively affected in 2003 by the payment of one additional month of interest income on our Note Receivable from Affiliate. Factors decreasing cash flows were higher priced gas inventories and higher prepayments due to increased collateral requirements on natural gas purchases.

During 2002, we paid more in tax payments and had one month less in interest payments on the Note Receivable from Affiliate.

During 2001, our recoveries from customers, related to UGAC, were higher due to an increase in underrecoveries at the end of 2000. Finally, in 2001, accounts payable related to our gas purchases were higher due to the requirements from some of our gas suppliers to accelerate payment for natural gas purchases.

Capital Expenditures and Investing Activities Cash used for capital expenditures and investing activities was \$125.5 million in 2003 as compared to \$141.1 million and \$146.7 million in 2002 and 2001, respectively. Our capital expenditures represent amounts spent on routine capital maintenance of our existing asset base and additions of new business services during the year.

Financing Activities During 2003, cash used for financing activities totaled \$111.5 million. The following summarizes significant items:

- Issuance of \$150 million of 11 1/2% Mortgage bonds;
- Receipt of \$127.8 million of prepaid interest under our Note Receivable from Affiliate;
- Redemption of \$190 million of our Mortgage bonds;
- Redemption of \$100 million of our 1-year term loan;
- Redemption of \$86.4 million of the IPSPT transitional funding trust notes; and
- Payment of \$2.3 million in preferred stock dividends.

During 2002, cash provided by financing activities totaled \$7.8 million. The significant items are as follows:

- Issuance of \$400 million of our 11 1/2 % Mortgage bonds;
- Borrowing of \$60 million under our 1-year term loan;
- Redemption of \$238.2 million in short-term debt;
- Redemption of \$95.7 million of our Mortgage bonds;
- Redemption of \$86.4 million of the IPSPT transitional funding trust notes ; and
- Payment of \$2.3 million in preferred stock dividends.

During 2001, cash used for financing activities totaled \$168.6 million. The following summarizes significant items:

- Issuance of \$186.8 million of variable rate Mortgage bonds;
- Borrowing of \$477.2 million in commercial paper;
- Redemption of \$186.8 of our variable rate Mortgage bonds;